Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2011-0319

IN THE MATTER OF the *Ontario Energy Board Act, 1998,* S.O. 1998, c.15, (Schedule B);

AND IN THE MATTER OF an application by Espanola Regional Hydro Distribution Corporation for an order approving or fixing just and reasonable rates and other charges for the distribution of electricity to be effective May 1, 2012.

BEFORE: Ken Quesnelle
Presiding Member

Cathy Spoel
Member

DECISION AND ORDER
September 27, 2012

Espanola Regional Hydro Distribution Corporation ("ERHDC") filed a cost of service application with the Ontario Energy Board on February 15, 2012. The Application was filed under section 78 of the *Ontario Energy Board Act, 1998* seeking approval for changes to the rates that ERHDC charges for electricity distribution to be effective May 1, 2012. The Board assigned the application file number EB-2011-0319

On March 2, 2012, the Board issued a letter to ERHDC identifying certain additional evidence that needed to be filed before the Board would consider the Application. ERHDC filed the requested additional evidence on March 7, 2012.

The Board issued a Notice of Application and Hearing on March 26, 2012. The Vulnerable Energy Consumers Coalition ("VECC") applied for and was given intervenor status and cost eligibility.

The Board issued Procedural Order No.1 and Order for Interim Rates on April 23, 2012. The Board made provision for ERHDC to file responses to all interrogatories. ERHDC filed responses to the interrogatories on June 8, 2012. Additional responses to the interrogatories were filed on June 28, 2012. Procedural Order No. 1 also established rates interim as of May 1, 2012 pending the outcome of this proceeding.

On June 29, 2012, the Board issued Procedural Order No.2 establishing dates for parties to provide submissions. Board staff filed its written submission on July 16, 2012 and VECC filed its written submission on July 20, 2012. Reply argument was filed by ERHDC on August 1, 2012.

ERHDC originally requested a service revenue requirement of $1,810,263 (or a base revenue requirement of $1,670,364) to be recovered in new rates effective May 1, 2012. The resulting requested rate increase was about $15.41 on the monthly bill for a Residential customer who consumes 800 kWh per month. A GS < 50 kW customer consuming 2,000 kWh per month would experience about $29.24 increase on the monthly bill. ERHDC's proposed rates are based on Modified International Financial Reporting Standards ("MIFRS").

In response to a Board staff interrogatory filed on June 8, 2012, ERHDC revised its service revenue requirement to $1,788,572 (or a base revenue requirement of $1,648,673). The updated proposed rates are set to recover a revenue deficiency of $423,422.

The full record is available at the Board's offices. The Board has chosen to summarize the record to the extent necessary to provide context to its findings.

ISSUES

Board staff and VECC made submissions on the following issues, which are addressed in this Decision:

- Operating Revenue;
- Operating, Maintenance & Administration Expenses ("OM&A");

- Rate Base and Capital Expenditures;
- Cost of Capital;
- Cost Allocation and Rate Design;
- Deferral and Variance Accounts;
- Smart Meters;
- Lost Revenue Adjustment Mechanism ("LRAM");
- Modified International Financial Reporting ("MIFRS");
- Rate Mitigation;
- Effective Date; and
- Implementation.

OPERATING REVENUE

The following issues are addressed in this section:

- Load Forecast;
- Customer Forecast; and
- Other Distribution Revenue.

Load Forecast

ERHDC's load forecast was developed in four steps. First, ERHDC developed a multivariate regression analysis that incorporates historical load and weather data from January 2003 to December 2010. Second, the 2011 Bridge and 2012 Test Year forecast were estimated by the model for weather normalization, using 8-year heating degree days and cooling degree days. Third, an adjustment was applied to the 2012 Test Year forecast to account for impact of the CDM target. Fourth, a forecast total use for each customer class was developed using customer count forecasts and then adjusting these forecasts based on relative weather sensitivity of each class so that the sum of individual class forecasts equaled the total billed kWh forecast developed in the first three steps.

ERHDC's proposed load forecast for 2012 is as follows:

Load and Demand Forecast

Rate Class	kWh	kW
Residential	32,680,721	
GS < 50 kW	11,265,899	
GS > 50 kW	17,442,772	44,045
Street Lighting	623,166	1,766
Unmetered Scattered Load	213,280	
Sentinel Lighting	24,161	66
TOTAL	**62,249,997**	

Board staff stated that the proposed load forecast for 2012 is slightly less than the average of the historic consumption; and noted that the difference is due to the CDM adjustment. ERHDC included 20% of its CDM targets. Board staff noted that the Board had accepted the inclusion of 20% of CDM targets into the load forecast for other distributors. Therefore Board staff submitted that the inclusion of the CDM adjustment in ERHDC's load forecast is reasonable. Staff had no concerns with the overall proposed load forecast.

VECC took no issues with the load forecasting methodology employed by ERHDC and explained that ERHDC's approach is similar to that used by a number of other electricity distributors.

VECC indicated that in its 2011 CDM actual savings, ERHDC only achieved 3% of its cumulative 2011-2014 CDM energy savings target and there was a question as to whether ERHDC would achieve the projected 20% of its CDM target. However VECC stated that there was no need to alter ERHDC's proposal provided an LRAM variance account was established as set out in the Board's issued CDM guideline.

BOARD FINDINGS

The Board finds that ERHDC's approach for the load forecast is reasonable and notes that in general the proposed load forecast is consistent with the historic consumption. The Board therefore accepts ERHDC's proposed load forecast for the purpose of setting 2012 rates. The Board notes that the inclusion of 20% of the CDM targets into the load forecast was generally acceptable to the parties and agrees with VECC that ERHDC will implement a LRAM variance account as set out in the Board's CDM Guidelines.

Customer Forecast

ERHDC's Test Year customer forecast is 4,410 customers/connections (including Street Lighting and Sentinel Lighting connections). The forecast was derived by applying the class specific historic annual growth rate for the Bridge and Test Years. Board staff stated that the customer forecast proposed by ERHDC was not significantly out of line with the historic period and had no concerns. VECC stated that the customer count had changed very little from year to year and submitted that the Board should accept ERHDC's customer forecast for the purpose of setting rates.

BOARD FINDINGS

The Board accepts ERHDC's proposed customer forecast for the purpose of setting 2012 rates.

Other Distribution Revenue

ERHDC forecasted total Other Distribution Revenue of $139,899 for the 2012 Test Year.

With the actual total Other Distribution Revenue for 2009 and 2010 in the level of $150,000, VECC had two concerns regarding the forecasted Merchandising & Jobbing revenue and Interest revenue. VECC stated that the 2010 and 2011 actual Merchandising & Jobbing revenue were over $7,500 each year and submitted that it is reasonable to increase the forecast 2012 Merchandising & Jobbing revenue to $4,000. Second, since ERHDC had not included any interest revenue in the forecasted revenue offset, the interest revenue of $1,000 should be included in the forecasted revenue offsets. Therefore, VECC submitted that with these two adjustments the 2012 revenue offset should be increased by $2,500.

In reply, ERHDC agreed with VECC's submission on revenue offsets and committed to increase the revenue offset by $2,500 in the draft Rate Order.

BOARD FINDINGS

The Board approves a revenue offset of $142,399 to reflect a $2,500 increase for the purpose of setting 2012 rates.

OPERATIONS, MAINTENANCE & ADMINISTRATION ("OM&A")

ERHDC is proposing a Test Year OM&A of $1,372,624 which represents a 16.5% increase over 2011 and a 42.4% increase over the 2008 Board approved OM&A.

VECC and Board staff both expressed concerns with the overall level of the proposed 2012 OM&A and provided their submissions on the following areas:

- Transition to IFRS;
- Vegetation Management; and
- Overall Increase in OM&A.

Transition to IFRS

ERHDC had originally forecasted $50,000 for consulting services for its transition from CGAAP to IFRS and proposed to recover $12,500 annually over 4 years commencing in 2012. Through the interrogatory responses, ERHDC removed the costs related to the transition to IFRS from the 2012 OM&A, since the costs would not be expected to be incurred in 2012.

Board staff noted that the removal of the costs was not reflected in the updated revenue requirement and stated that ERHDC should record any future costs in the Board approved Account 1508. ERHDC stated in its reply that it agreed with Board staff and would include the adjustment to its 2012 OM&A in the draft Rate Order.

BOARD FINDINGS

The Board accepts the removal of $12,500 from the proposed OM&A for 2012 as stated in ERHDC's reply submission.

Vegetation Management

ERHDC filed a revision to its tree trimming costs for lines at Bass Lake Road and all other lines. Board staff expressed concern regarding the proposed tree trimming costs for lines, except Bass Lake Road. Board staff stated that the substantial increase in the test year had not been well justified or explained and noted that in the absence of more clarification from ERHDC, the Board may wish to deem the proposed tree trimming costs of $83,500 which is based on the historic average tree trimming costs.

VECC stated that a large component of the increase under Maintenance costs was related to tree trimming costs. And VECC noted that the vegetation management plan was not part of the Asset Management Plan performed by outside consultants and also questioned why the vegetation management work had not been undertaken in the past under IRM rates. Since the occurrence of power outages due to trees had fallen in recent years, VECC further questioned whether the data supports the accelerated tree trimming program proposed by ERHDC.

ERHDC replied that it had corrected the oversight and mistake in the proposed tree trimming costs which indicated that the 2012 per km cost is lower than 2010 per km cost. ERHDC also submitted that the annual kms of lines to be cleared should be revised from 14kms to 40kms. ERHDC stated that the costs proposed by Board staff are less than the current inadequate level and submitted that the 2012 tree trimming costs should be at the level of $186,001, including the costs for Bass Lake Road.

Year		2008	2009	2010	2011	2012	2013	2014	2015
13km Bass Lake Road – One time	Costs					$37,500	$37,500	$37,500	$37,500
	Costs / km					3.25km $11,538/km	3.25km $11,538/km	3.25km $11,538/km	3.25km $11,538/km
13km Bass Lake Road – Ongoing	Costs				$10,000				
	Costs / km				1 km $10,000/km				
All other lines	Costs	$64,272	$100,443	$135,566	$113,916	$148,501	$148,501	$148,501	$148,501
	Costs / km	28km $2,295/km	36km $2,790/km	34km $3,987/km	11km $10,356/km	40km $3,713/km	40km $3,713/km	40km $3,713/km	40km $3,713/km
Total	Costs	$64,272	$100,443	$135,566	$123,916	$186,001	$186,001	$186,001	$186,001

In its reply argument, ERHDC broke down its justification for the proposed vegetation management into four areas as follows.

Timing and Need

ERHDC stated that its evidence had indicated that there was significant back log developed in the rural areas. ERHDC described areas where the conductors are touching the vegetation and burning or the line is barely visible through the vegetation.

Safety
ERHDC stated that it is committed to the safety of the public, customers and employees. ERHDC went on to reiterate that lines are touching vegetation and provided explanations as to how this situation could lead to electrocution of workers or members of the public. It further explained how the current situation has the potential for causing forest fires.

Reliability Statistics
With regards to the reliability statistics, ERHDC stated that the use of fuses rather than electronic relaying allows the vegetation to be in contact with the primary lines and burn rather than to having an outage, which explained the improvement in SAIDI and SAIFI, despite an excessive amount of tree contact with the lines. ERHDC reminded the Board that its increased tree trimming efforts are to ensure safety not reliability.

Line Losses
ERHDC submitted that its line losses would be reduced due to the reduced tree contact.

BOARD FINDINGS

While the Board accepts ERHDC's proposed costs for vegetation management the Board finds it necessary to remind ERHDC that it has a responsibility to maintain a safe and reliable distribution system on an ongoing basis. It is not appropriate or acceptable to present known and existing safety hazards such as have been listed in ERHDC's reply in order to persuade the Board that its proposed vegetation management costs are reasonable. The grim state of affairs attributable to the lack of vegetation management cannot be justified on the basis of a revenue deficiency.

As an economic regulator the Board ensures that ratepayers are paying just and reasonable rates. It does so by periodically assessing the reasonableness of the utility's ongoing costs related to operations, maintenance, administration and its capital expansion and replacement programs. There is nothing in this regulatory ratemaking framework that makes it acceptable for a distribution company to operate at anything less than an acceptable level of safety at all times.

It is clear to the Board that sufficient revenues are required to maintain a distribution system such that it is safe. That does not mean that an unsafe system can ever be justified due lack of funds. Where an undue risk to workers or the public exists ERHDC has a duty to remedy the situation. That duty is not conditional on the basis of affordability.

Overall Increase in OM&A

VECC submitted that ERHDC's OM&A should be set at the range between $1,075,000 and $1,100,000, which would be slightly higher than the 2011 actual spending.

VECC conducted an "expected cost growth" analysis in assessing the reasonableness of ERHDC's overall OM&A proposal. VECC's methodology adjusts the last Board approved OM&A by inflation, customer growth and allows for incremental utility responsibilities and unavoidable activities. In VECC's submission, the inflation and customer growth adjustment would yield a factor ranging between 10.5% and 11.5% and therefore an expected OM&A between $1,065,474 and $1,075,116. VECC's submission then provided for incremental increases of $100,000 related to accounting changes, smart meters, and increased regulatory burden. With the total incremental costs, VECC stated that the resulting expected OM&A costs would be between $1,075,000 and $1,100,000.

Board staff noted that the proposed 2012 OM&A represented an annual average increase of approximately 11% as compared to the 2008 Board Approved OM&A. In 2010, the OM&A level represented an average annual increase of 3.4% as compared to the Board Approved 2008 level. Board staff submitted that if the Board reduced ERHDC's OM&A for the tree trimming costs identified in Board staff's submission, the 2012 OM&A would be $1,253,623, and would represent an approximate 7.5% annual increase from the 2008 Board Approved amount. While the increase of the reduced 2012 OM&A is still higher than ERHDC's historic increase, Board staff submitted that ERHDC had justified this level of costs. Board staff's position results in an overall decrease of 8.7% from the amount requested by ERHDC.

ERHDC did not reply to the submissions on its overall increase in OM&A.

BOARD FINDINGS

The Board accepts the overall OM&A costs in that it accepts the costs associated with the component parts. The Board considers ERHDC to be in a period of accelerated maintenance due to past neglect in certain areas of spending. The Board expects the level of OM&A applied for by ERHDC in its next rebasing to be reflective of this and calibrated accordingly.

PAYMENTS IN LIEU OF TAXES ("PILs")

ERHDC provided an updated provision for PILs of $9,329 in response to interrogatories. Board staff and VECC made no submissions on the calculation as filed.

BOARD FINDINGS

The Board notes that the level of PILs will be updated on the basis of the Board's findings regarding the rate base and operating expenditures. The draft Rate Order should provide sufficient details of the calculations. Subject to confirmation of the calculations in the draft Rate Order, the Board approves the PILs proxy proposed by ERHDC and as amended in interrogatories.

DEPRECIATION

ERHDC proposed a total depreciation expense of $175,539 in 2012. Board staff made no submissions on the proposed amount as filed. VECC noted that for some assets ERHDC had proposed different useful lives from the typical lives used in the Kinectrics Report. VECC stated that in the absence of a utility specific study, the typical useful lives in the Kinectrics Report should be used; however VECC indicated that the differences were not material.

BOARD FINDINGS

The Board finds that the proposed depreciated rates are reasonable and approves a total depreciation expense of $175,539 for the purpose of setting 2012 rates.

RATE BASE AND CAPITAL EXPENDITURES

ERHDC requested approval of a rate base of $4,246,610 in this Application, which represented a 46% increase from the 2010 actual amount and a 56% increase from the 2008 Board approved amount. The proposed rate base is based on Modified International Financial Reporting Standards ("MIFRS").

The following areas are addressed in this section:

- Capital Expenditures;

- Working Capital Allowance; and
- Green Energy Act Plan.

Capital Expenditures

ERHDC proposed capital expenditures of $1,025,592 in 2012 including $655,906 in smart meter expenditures. Board staff observed that ERHDC's historical capital expenditures had fluctuated significantly, but also recognized that for a small utility a single project could increase the total capital expenditure by a considerable amount. Board staff further stated that the proposed 2012 capital expenditures excluding smart meter expenditures would be $369,686, which are in line with the average of the historic capital expenditures and had no concerns.

VECC noted that vehicles accounted for a disproportionate amount of ERHDC's capital expenditures and encouraged ERHDC to reduce costs by sharing or having a service agreement with neighboring utilities. VECC also submitted that ERHDC should update its opening balance of the 2012 rate base to reflect the actual capital expenditures of 2011.

In its reply submission, ERHDC submitted that the change in rate base due to 2011 actual capital expenditures would be a reduction of $31,035. Given the regulated return on rate base of 6.20%, the reduction in return would be $1,924. ERHDC agreed that the rate base could be updated based on the 2011 actual amount; however submitted that materiality should also be considered.

BOARD FINDINGS

The Board approves ERHDC's proposed capital expenditures in 2012. The Board is of the view that the proposed capital expenditures, excluding smart meter costs, are consistent with the historic spending level. The Board finds that the update of 2011 actual capital expenditures is not necessary as it is not material and will not direct ERHDC to make this adjustment.

Working Capital Allowance

ERHDC calculated its Working Capital Allowance using the 15% allowance approach and proposed $1,139,886 as the Working Capital Allowance for 2012. Board staff made no submission on working capital allowance.

VECC submitted that ERHDC should be required to use the working capital amount of 13% as outlined in the Board's letter dated April 12, 2012. VECC argued that the default value of 15% is excessive in relation to the needs of most utilities which had been borne out by various lead-lag studies submitted before the Board over the past two years. VECC further stated that ERHDC should use the Board's best information in its application and should not rely on the year for which rates were filed.

ERHDC replied that using the default 15% working capital allowance is consistent with the Board's filing requirement and noted that only 2013 cost of service applicants were required to use a default value of 13%. ERHDC stated that it did not have any evidence to support the assertion that 13% would be appropriate in its circumstances and submitted that it is inappropriate to arbitrarily impose the value for 2013 in its 2012 application.

BOARD FINDINGS

The Board agrees with ERHDC that using the default 15% working capital allowance is consistent with *Chapter 2 of the Filing Requirements for Transmission and Distribution Application* issued June 22, 2011.

Green Energy Act Plan

ERHDC applied for approval of its Basic Green Energy Act Plan ("GEA Plan") but did not seek any cost recovery in this application. In its GEA Plan, ERHDC provided a summary of the renewable project applications, assessment of its distribution feeders, constraints of its substations and mitigation plan.

Board staff concluded that there are no investments in the five year horizon of the GEA Plan that could be categorized as either directly related to connection of renewable generation or to investment in smart grid. Board staff submitted that the Board should not approve EHRDC's GEA Plan as there was no cost recovery proposed, nor had ERHDC properly classified its asset management activity. However, Board staff also commented that ERHDC has met the requirements under the Board's Distribution System Planning Filing Requirements.

VECC acknowledged that ERHDC had provided substantive evidence in support of the future building of a new distribution substation and for the rebuilding of three existing stations; however VECC noted that ERHDC had not indicated whether it would file a capital adjustment application under IRM in the future and details on how to finance these investments.

In reply, ERHDC indicated that it intended to apply for recovery in the 2013 IRM year utilizing the incremental capital module (ICM) to address the treatment of new capital needs. ERHDC also stated that it would finance these investments through third party borrowing.

BOARD FINDINGS

The Board notes that ERHDC has filed its Basic Green Energy Act Plan with no cost recovery proposed, and no classifications on investments related to connection of renewable generation or to investment in smart grid were provided. The Board finds that the evidence provided does not allow for a proper approval of the GEA Plan. The Board is of the view that ERHDC has met the requirements under the Board's Distribution System Planning Filing Requirements and no further action is required by ERHDC at this time.

The Board acknowledges that ERHDC intends to utilize the incremental capital module (ICM) to address the treatment of new capital needs. The Board will examine the prudence of the costs proposed by ERHDC upon filing of the ICM at a later date.

COST OF CAPITAL

ERHDC's proposed test year Cost of Capital as set out in the original application is summarized in the following table.

Cost of Capital Parameter	ERHDC's Proposal
Capital Structure	60.0% debt (composed of 56.0% long-term debt and 4.0% short-term debt) and 40.0% equity
Short-Term Debt	2.08%
Long-Term Debt	5.01%
Return on Equity (ROE)	9.42%
Weighted Average Cost of Capital	6.66%

ERHDC has a note payable to the Town of Espanola and a note payable to the Township of Sables-Spanish. The interest rate of the notes would be adjusted periodically to the Board's deemed interest rate.

On March 2, 2012, the Board issued a letter documenting the updated Cost of Capital parameters to be used in the 2012 cost of service applications for rates effective May 1, 2012. These are summarized in the following table:

Cost of Capital Parameter	Updated Value for 2012 Cost of Service Applications for rates effective May 1, 2012
Return on Equity	9.12%
Deemed Long-term Debt Rate	4.41%
Deemed Short-term Debt Rate	2.08%

Board staff noted that through its interrogatory response, ERHDC had updated its rates to reflect the cost of capital parameters issued on March 2, 2012 and had no concerns with the treatment of the cost of capital components. VECC also supported the updated cost of capital parameters which should be used in filing the draft Rate Order.

BOARD FINDINGS

The Board accepts ERHDC's updated rates to reflect the cost of capital parameters issued on March 2, 2012.

COST ALLOCATION AND RATE DESIGN

The following issues are addressed in this section:

- Cost Allocation;
- Monthly Service Charges ("MSC");
- Retail Transmission Service Rates ("RTSR");
- Low Voltage Charges; and
- Loss Factors.

Cost Allocation

The following table sets out ERHDC's current and proposed revenue-to-cost ratios and the Board's targets, as established in the Board's *Review of Electricity Distribution Cost Allocation Policy* (EB-2010-0219).

Revenue-to-Cost Ratios

Customer Class	Updated Current Ratios	Proposed Ratios for Test Year	Board's Target Range - Floor	Board's Target Range - Ceiling
Residential	93.4%	95.2%	85%	115%
GS < 50 kW	113.9%	115.9%	80%	120%
GS > 50 kW	135.7%	120.0%	80%	120%
Street Lighting	68.7%	70.0%	70%	120%
Sentinel Lighting	68.3%	80.0%	80%	120%
Unmetered Scattered Load	114.3%	114.9%	80%	120%

Before any adjustments, the GS > 50 kW class exceeded the ceiling of the Board's target ranges and the Street Lighting and Sentinel Lighting classes fell below the floor of the Board's target ranges. ERHDC proposed to move the Street Lighting and Sentinel Lighting classes to the floor of the respective target ranges and move the GS > 50 kW class to the ceiling of the target range on one year.

VECC submitted that this approach is appropriate and consistent with what had been approved by the Board for other distributors. Given that all the classes are within the Board's target ranges, Board staff had no concerns with the revenue-to-cost ratio proposal.

BOARD FINDINGS

The Board finds that the proposed revenue-to-cost ratios are reasonable and consistent with the Board's revenue-to-cost ratio policy.

Monthly Service Charges ("MSC")

ERHDC is proposing to maintain the same fixed/variable proportions for all the customer classes. The proposed MSC are all within the Board's policy ranges, except for the GS > 50 kW class. ERHDC's current and proposed MSCs are presented in the following table:

Rate Class	Monthly Service Charges	
	Current	Proposed
Residential	$9.96	$13.70
GS < 50 kW	$17.95	$24.54
GS > 50 kW	$161.36	$190.93
Street Lighting	$1.40	$1.93
Sentinel Lighting	$1.29	$2.09
Unmetered Scattered Load	$8.82	$11.94

Board staff recognized that the MSC for GS > 50 kW class exceeds the Board's ceiling; however staff submitted that to maintain the existing fixed/variable proportion is reasonable and consistent with the Board's past decisions.

VECC submitted that the MSC for GS > 50 kW class should be maintained at the 2011 level of $161.36. VECC explained that the MSC for GS > 50 kW should not be increased further since the current MSC was already above the ceiling.

In its reply submission, ERHDC submitted that to maintain the same fixed/variable portions for all the customer classes is consistent with the Board's past decisions.

BOARD FINDINGS

The Board approves ERHDC's proposed MSC which maintains the existing fixed/variable proportions. The Board notes that the MSC for GS> 50 kW class exceeds the target ceiling, but recognizes that maintaining the fixed/variable proportions are consistent with the Board's past decisions.

Retail Transmission Service Rates ("RTSR")

In response to a Board staff interrogatory, ERHDC updated its proposed RTSRs to reflect expiration of rate riders which are under a Hydro One Sub-Transmission classification. The updated RTSRs are shown in the following table.

Rate Class	ERHDC Updated Proposal	
	RTSR Network	RTSR Connection
Residential ($/kWh)	$0.0056	$0.0041
GS < 50 kW ($/kWh)	$0.0052	$0.0037
GS > 50kW ($/kW)	$2.0890	$1.4334
GS > 50kW – Interval Metered ($/kW)	$2.3482	$1.9855
Street Lighting ($/kW)	$1.5755	$1.1080
Unmetered Scattered Load ($/kWh)	$0.0052	$0.0037
Sentinel Lighting ($/kW)	$1.5835	$1.1312

Board staff took no issue with the revised RTSRs and VECC submitted that the revised charges should be approved for 2012 rates.

BOARD FINDINGS

The Board accepts the revised Retail Transmission Service Rates proposed for 2012.

Low Voltage Charges

In its original application, ERHDC forecasted its Low Voltage (“LV”) costs to be $144,544. In response to a Board staff interrogatory, ERHDC revised its LV costs to $229,288 and indicated that the revised value is based on the current Hydro One rates.

Board staff confirmed that the calculations of the LV costs are based on the latest approved rates for Hydro One Network Inc. and has no concerns with the proposed costs. However since the proposed LV costs are approximately 14% of the proposed based revenue requirement, Board staff submitted that ERHDC should explore any alternatives that could lead to a reduction of the LV costs in the future.

VECC noted that since Hydro One’s LV charges for 2012 are the same as for 2011; it submitted that the LV costs should be $208,590 which is calculated based on ERHDC’s 2011 actual LV costs with the adjustment for the 2012 load forecast.

In reply, ERHDC agreed with Board staff’s submission on the proposed LV costs and noted that it was more cost effective to be an embedded distributor but would continue to explore this area in the future to reduce LV costs. ERHDC did not respond to VECC’s submission.

BOARD FINDINGS

The Board approves the LV costs of $229,288 and acknowledges ERHDC's commitment that it will explore alternatives to reduce LV costs in the future.

Loss Factors

ERHDC applied for a Total Loss Factor ("TLF") of 1.0714 (for secondary metered customers < 5,000 kW), which is based on an underlying Distribution Loss Factor ("DLF") of 1.0527 and Supply Facility Loss Factor ("SFLF") of 1.0178. The proposed DLF and SFLF are based on the average of five historical years from 2006 to 2010. The current approved TLF for secondary metered customers < 5,000 kW is 1.0543.

Board staff had a concern with the proposed loss factors in that they are above 5% and proposed two options to the Board. The Board may wish to approve the proposed TLF and direct ERHDC to address the higher level of DLF in the next cost of service application by developing and filing a plan to reduce losses. The second option was to deem a DLF of 5% for the purpose of this application and direct ERHDC in the next cost of service application to file a plan to reduce losses.

ERHDC replied that it expected that the additional line clearing proposed in this application would result in reduction of lines losses in future years and would concur if the Board would deem a DLF of 5%.

BOARD FINDINGS

The Board will apply a DLF of 5% for the purposes of setting rates. ERHDC is of the belief that its line clearing operations will have a positive impact on it line losses. The Board draws no conclusions in that regard but nevertheless accepts ERHDC's proposal to set the DLF at 5%.

DEFERRAL AND VARIANCE ACCOUNTS

The following issues are addressed in this section:

- Balances Proposed for Disposition; and
- Review and Disposition of Account 1562: Deferred Payments in Lieu of Taxes.

Balances Proposed for Disposition

ERHDC is requesting disposition of the Group 1 and Group 2 deferral and variance account principal and interest balances as at December 31, 2010 and the forecasted interest through April 30, 2012 over a one year period.

Account Balances for Disposition

Account #	Account Description	Disposition Amount
1550	LV Variance Account	($9,996)
1580	RSVA – Wholesale Market Service Charge	($137,250)
1584	RSVA – Retail Transmission Network Charge	$676
1586	RSVA – Retail Transmission Connection Charge	($9,298)
1588 – Pwr	RSVA – Power (excluding Global Adjustment)	$280,208
1588 – GA	RSVA – Power – Sub account -Global Adjustment	($5,199)
1508	Other Regulatory Assets – Incremental Capital Charges	$2,409
1562	Deferred Payments in Lieu of Taxes	($26,978)
1592	PILs/Taxes Variance for 2006 and subsequent years	$8,443
1592 – ITC	PILs/Taxes Variance, Sub-account HST/OVAT Input Tax Credit	($7,888)
	Total Proposed for Disposition	**$105,854**

Board staff noted that the balances as of December 31, 2010 are consistent with ERHDC's RRR filings, except for account 1562. Board staff had no concerns with the proposed disposition other than for account 1562. VECC had no comments on the proposed disposition.

BOARD FINDINGS

The Board approves the disposition of the Group 1 and Group 2 deferral and variance account principal and interest balances as at December 31, 2010 and the forecasted interest through April 30, 2012 over a period that maintains a rate impact of less than 10% for all rate classes. . The Board will make findings for account 1562 in the section below.

Review and Disposition of Account 1562: Deferred Payment in Lieu of Taxes

In 2001, the Board approved a regulatory payments in lieu of taxes proxy approach for rate applications coupled with a true-up mechanism filed under the RRR to account for changes in tax legislation and rules and to true-up between certain proxy amounts used to set rates and the actual amount of taxes paid. The variances resulting from the true-up were tracked in Account 1562 for the period 2001 through April 30, 2006.

On November 28, 2008, pursuant to sections 78, 19 (4) and 21 (5) of the Act, the Board commenced a Combined Proceeding (EB-2008-0381) on its own motion to determine the accuracy of the final account balances with respect to Account 1562 Deferred Payments in Lieu of Taxes ("Deferred PILs") (for the period October 1, 2001 to April 30, 2006) for certain electricity distributors that filed 2008 and 2009 distribution rate applications.

The Notice in the Combined Proceeding included a statement of the Board's expectation that the decision resulting from the Combined Proceeding would be used to determine the final account balances with respect to Account 1562 Deferred PILs for the remaining distributors. In its Decision and Order, the Board stated that: "Each remaining distributor will be expected to apply for final disposition of account 1562 with its next general rates application (either IRM or cost of service)."[1]

In its application, ERHDC applied to refund to its customers a credit balance of $26,978 consisting of a principal amount of $24,804 plus related carrying charges of $2,174.

Board staff raised an issue about excess interest true-up in its submission and submitted that interest on regulatory asset variance accounts and on PILs assessments should be excluded from the true-up calculations to be consistent with the Board's previous decision. Board staff also submitted that fees charged on IESO or other prudential letters or lines of credit should be included in the true-up calculations to be consistent with the Board's previous decisions on similar matters. As such, Board staff stated that the revised credit amount should be approximately $28,245 consisting of a principal credit amount of $25,910 plus related carrying charges of $2,335.

In its reply submission, ERHDC agreed that the credit balance of $28,245 should be returned to its customers.

BOARD FINDINGS

The Board accepts Board staff's approach to Account 1562 to address the interest claw back issue and approves the disposition of a credit balance of $28,245 which ERHDC

[1] Decision and Order on Account 1562 Deferred PILs Combined Proceeding (EB-2008-0381), p. 28

had agreed to. The Board finds that the approved amount to be returned to customers is consistent with previous regulatory guidance and past decisions of the Board. ERHDC should include this balance in the Group 1 and Group 2 deferral and variance account balances to be refunded through rate riders resulting from this Decision.

For accounting and reporting purposes, the balance of Account 1562 shall be transferred to the applicable principal and interest carrying charge sub-accounts of Account 1595 pursuant to the requirements specified in Article 220, Account Descriptions, of the Accounting Procedures Handbook for Electricity Distributors. The date of the journal entry to transfer the approved account balances to the sub-accounts of Account 1595 is the date on which disposition of the balances is effective in rates, which generally is the start of the rate year (e.g. May 1). This entry should be completed on a timely basis to ensure that these adjustments are included in the September 30, 2012 RRR data to be filed with the Board by November 30, 2012.

SMART METERS

ERHDC is requesting the approval of its smart meter capital and OM&A costs on a final basis to the end of 2011, a 24 month smart meter disposition rate rider ("SMDR") to recover the residual balance in the smart meter variance accounts, and a 24 month stranded meter rate rider ("SMRR") to recover the net book value of the removed from service stranded meters.

Prudence of Smart Meter Costs

In its evidence, ERHDC stated that it followed the London RFP Procurement process and completed the installation of smart meters in 2011. Based on the evidence as of the close of the discovery phase, Board staff documented cost per installed smart meter as $236.63.

ERHDC included $20,366 of capital costs for beyond minimum functionality expenses. Board staff also noted that the corresponding capital costs had been included in rate base. Board staff submitted that per meter costs are reasonable as compared to the costs the Board has seen for most utilities that had filed applications to date.

BOARD FINDINGS

The Board notes that authorization to procure and deploy smart meters has been done in accordance with Government regulations, including successful participation in

London Hydro RFP process, overseen by the Fairness Commissioner, to select (a) vendor(s) for the procurement and/or installation of smart meters and related systems. There is thus a significant degree of cost control discipline and distributors, including ERHDC, are subject to in the procurement and deployment of smart meters.

The Board finds that ERHDC's documented costs related to smart meter procurement, installation and operation, and associated equipment, are reasonable. As such, the Board approves the recovery of the costs for smart meter deployment and operation as of December 31, 2011.

Smart Meter Disposition Rate Rider

ERHDC is requesting class-specific SMDRs to recover the remaining revenue requirement for the 2007 to 2011 period of smart meters installed up to the end of 2011. The SMDR takes into account the actual revenue collected to the end of April 2012 through the Smart Meter Funding Adder. The net result is a recovery amount of $184,091 that would be recovered over the May 1, 2012 to April 30, 2014.

In response to a Board staff interrogatory, ERHDC confirmed that it proposed to allocate costs to each class on the following basis:

- Return (deemed interest plus return on equity) was allocated based on the number of smart meters installed by rate class;
- Amortization was allocated based on the smart meter costs per rate class;
- OM&A expenses were allocated based on the number of meters installed for each class;
- Payments in lieu of taxes ("PILs") were allocated based on the revenue requirement allocated to each class before PILs; and
- Smart Meter Funding Adder revenues, including carrying costs, were allocated based on the actual amounts collected from each class.

Board staff submitted that cost causality should be the guiding principle when allocating costs to each class. Board staff submitted that the cost allocation for the return should be based on the smart meter costs by rate class. VECC supported Board staff's submission.

In reply, ERHDC agreed with Board staff that it is more appropriate to allocate the return based on smart meter costs. ERHDC provided updated SMDR calculations shown in the table below.

Rate Class	SMDR ($/month)
Residential	$2.23
GS < 50 kW	$2.88
GS > 50 kW	$5.50

BOARD FINDINGS

The Board approves ERHDC's revised cost allocation methodology as it is consistent with the approach approved by the Board in PowerStream's smart meter cost recovery application (EB-2011-0128). The Board will approve the updated class-specified SMDRs to be collected over a period that maintains a rate impact of less than 10% for all customer classes. The Board will approve an effective date of May 1, 2012 and will approve an implementation date of November 1, 2012.

Stranded Meters

ERHDC is requesting to recover the net book value of the removed from service stranded meters through class-specific SMRRs over a 2-year period. Board staff had no concerns with the proposed amount of $87,767 and the recovery period. ERHDC provided the class-specific SMRRs shown in the table below.

Rate Class	SMRR ($/month)
Residential	$1.04
GS < 50 kW	$1.37
GS > 50 kW	$4.30

VECC supported ERHDC's proposal for recovery of stranded meter costs.

BOARD FINDINGS

The Board approves the proposed class-specified SMRRs to be collected over a period that maintains a rate impact of less than 10% for all customer classes. The Board will approve an effective date of May 1, 2012 and will approve an implementation date of November 1, 2012.

LOST REVENUE ADJUSTMENT MECHANISM (“LRAM”)

ERHDC is seeking LRAM recovery of $160,270 for legacy programs to be recovered over a three year period. The lost revenues included the effect of CDM programs implemented from 2006 to 2010 for the period 2006 to 2012.

Board staff supported the recovery of the required LRAM amounts in 2006, 2007, 2008, 2009 and 2010. However, Board staff submitted that it is premature to consider recovery of lost revenues persisting in 2011 or 2012. Board staff requested that ERHDC provide an updated LRAM amount and subsequent rate riders that included lost revenues from 2006 to 2010 CDM programs during the 2006 to 2010 period only.

VECC supported Board staff’s proposal on the LRAM adjustments.

In reply, ERHDC provided an updated LRAM amount and rate riders that excluded the lost revenues for 2011 and 2012. The updated LRAM amount is $152,728.

BOARD FINDINGS

The Board approves the updated LRAM amount of $152,728 which represents the effect of CDM programs implemented from 2006 to 2010 for the period 2006 to 2010. The Board agrees with Board staff that the recovery of the lost revenue for the persistence from 2006 to 2010 programs in 2011 and 2012 is premature to do so and inconsistent with the LRAM Guidelines.

MODIFIED INTERNATION FINANCIAL REPORTING (“MIFRS”)

In its response to a Board staff interrogatory, ERHDC provided a revised calculation of the balance for closing net Property, Plant and Equipment (“PP&E”) between CGAAP and MIFRS of $94,495. ERHDC proposed to amortize the balance over a four year period. As a result, the annual amortization amount is a balance of $23,624. ERHDC calculated the return on rate base of $5,859. Board staff also noted that the revised calculation of the PP&E balance of $29,483 reflected the weighted average cost of capital (WACC) of 6.20%.

BOARD FINDINGS

The Board approves the revised PP&E balance of $29,483 to be recovered over a four year period. The Board notes that the PP&E deferral account is designed to capture the

PP&E difference caused by the transition from CGAAP to MIFRS and that ERHDC has calculated the balance in accordance with Board guidance on this matter.

RATE MITIGATION

In its submission, Board staff noted that the total bill impact calculation provided by ERHDC indicates that increases exceed 10% for all rate classes except for GS > 50 kW. Staff also noted that ERHDC did not provide a rate mitigation plan to address this issue. Staff submitted that depending on the outcome of the Board's decision, a mitigation plan may still be required to be filed as part of the draft Rate Order.

In reply, ERHDC stated that if ERHDC has a rate class with a total bill impact over 10% in the draft Rate Order, a rate mitigation plan would be proposed.

BOARD FINDINGS

While ERHDC has not provided a rate mitigation at this point, should ERHDC determine that rate impacts in its draft Rate Order would exceed the 10% total bill threshold for typical customers in any class, ERHDC should document this and propose a reasonable plan to address such a situation.

EFFECTIVE DATE

ERHDC applied for rates effective May 1, 2012. In Procedural Order No. 1 and Order for Interim Rates, the Board declared ERHDC's current rates interim, which allows for an effective date as early as May 1, 2012.

VECC noted that on January 26, 2012 the Board sent a letter to ERHDC indicating that for rates to be effective May 1, 2012 it should have filed an application by August 26, 2011. VECC also noted that ERHDC filed an incomplete application on February 15, 2012 and the complete application was accepted on March 7, 2012; nevertheless no reasons were given for the late filing. VECC submitted that no compensation should be provided by ratepayers for the late filing of this application. VECC further stated that rates should be made effective in the normal course and on the date of, or subsequent to, the issuance of a final Rate Order. Board staff made no submission on this matter.

BOARD FINDINGS

The Board has determined that ERHDC's new rates will become effective May 1st 2012.

In this decision the Board has made findings regarding the revenue requirement based partly on the apparent historic lack of sufficient maintenance of the distribution system. The Board has also expressed its expectation that ERHDC's rebased revenues will be used to correct for this historic neglect and that a recalibration of its revenue requirements at its next rebasing will be reflective of this next period of accelerated maintenance.

The Board notes VECC's submission regarding its concern that ratepayers should not bear the financial brunt of the applicant's late filing. While the Board generally agrees with VECC's views on this point, but in this case it will allow for the full period of recovery requested by ERHDC so as to allow the necessary works to be completed. The Board does so with the ratepayer in mind from a service delivery point of view.

The Board considers this to be an exceptional case; one where the Board found it necessary to remind the applicant of the tenets of ratemaking and of the inappropriateness of relying on the establishment of a revenue requirement to initiate works related to maintaining a sufficiently safe distribution system. The Board fully expects ERHDC to file its next rebasing application on time and based on a revenue requirement deigned to **maintain** (not create) a safe and reliable distribution system.

The Board has also determined that the implementation date will be November 1, 2012. The Board notes that there is an overall revenue deficiency that arises out of this Decision. The Board directs ERHDC to dispose of any deficiency arising from this Decision for the period May 1, 2012 to the implementation date by calculating class specific volumetric rate riders that would recover from customers the stub period amount over a period that maintains a rate impact of less than 10% for typical customers in all rate classes. If reducing the impact for all classes to less than 10% on total bill is not possible while maintaining a reasonable recovery period, ERHDC may provide an alternative mitigation plan as part of its draft Rate Order. ERHDC should also provide the detailed calculations of the rate riders in its draft Rate Order.

IMPLEMENTATION

The Board has made findings in this Decision which change the 2012 revenue requirement and therefore change the distribution rates from those proposed by ERHDC. In filing its draft Rate Order, the Board expects ERHDC to file detailed supporting material, including all relevant calculations showing the impact of this Decision on ERHDC's revenue requirement, the allocation of the approved revenue requirement to the classes and the determination of the final rates. Supporting documentation shall include, but not be limited to, filing a completed version of the Revenue Requirement Work Form Excel spreadsheet, which can be found on the Board's website.

A Rate Order will be issued after the steps set out below are completed.

1. ERHDC shall file with the Board, and shall also forward to VECC, a draft Rate Order attaching a proposed Tariff of Rates and Charges reflecting the Board's findings in this Decision within **14 days** of the date of the issuance of this Decision. The draft Rate Order shall also include customer rate impacts and detailed supporting information showing the calculation of the final rates including the Revenue Requirement Work Form in Microsoft Excel format.

2. Board staff and VECC shall file any comments on the draft Rate Order with the Board and forward to ERHDC within **7 days** of the date of filing of the draft Rate Order.

3. ERHDC shall file with the Board and forward to VECC responses to any comments on its draft Rate Order within **4 days** of the date of receipt of Board staff and VECC comments.

COST AWARDS

The Board may grant cost awards to eligible parties pursuant to its power under section 30 of the *Ontario Energy Board Act, 1998*. When determining the amount of the cost awards, the Board will apply the principles set out in section 5 of the Board's *Practice Direction on Cost Awards*. The maximum hourly rates set out in the Board's Cost Awards Tariff will also be applied.

1. VECC shall file with the Board and forward to ERHDC their respective cost claims within **7 days** from the date of issuance of the final Rate Order.

2. ERHDC shall file with the Board and forward to VECC any objections to the claimed costs within **14 days** from the date of issuance of the final Rate Order.

3. VECC shall file with the Board and forward to ERHDC any responses to any objections for cost claims within **21 days** of the date of issuance of the final Rate Order.

4. ERHDC shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

All filings with the Board must quote the file number EB-2011-0319, and be made through the Board's web portal at https://www.pes.ontarioenergyboard.ca/eservice/, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must be received by the Board by 4:45 p.m. on the stated date. Parties should use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available, parties may e-mail their documents to the attention of the Board Secretary at BoardSec@ontarioenergyboard.ca.

DATED at Toronto, September 27, 2012
ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary